Developing Demand-Response Based Solutions for Hawaii's 100% Renewable Energy Target

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Master's Thesis

Acknowledgments

This report is the culmination of work done over a six-month period, alongside the Rocky Mountain Institute (RMI)'s Electricity practice and the Public Utilities Commission (PUC) of Hawaii. To that end, I would first likely to thank my company advisor, Dan Cross-Call, without whom this project would not have been possible. Working with Dan and the team and having my algorithm logic reviewed and critiqued by them was essential to the final product. I learned a great deal during my time here – how reasonable assumptions are made in modeling and how they can be instrumental in a multi-variable, complex scenario.

I would also like to thank the Hawaii PUC for being great collaborators and for offering invaluable constructive feedback that ultimately ensured we made a better product. I would like to thank my academic supervisor, Enrique Velo, along with UPC – for providing the right academic curriculum that made me able to participate in and learn from this project.

Last, but not the least, I would like to thank my parents for their continued support of my work.

Abstract

The State of Hawaii has set a target to achieve a 100% Renewables by 2045. Due to the State's high electricity prices and dependence on imported oil, renewables are seen as an environmental and economic solution to the problem. While the state has seen substantial renewables growth in the last few years, a truly transformative system is needed to push for a fully renewable future. This system would be likely to include Demand Response (DR) capability, Distributed Energy Resources and the like. This report models various different scenarios – different rate schedules, energy storage and energy production technologies – to determine which combination can deliver the most economic value.

Time-of-Use and Flat Rate Schedules form the basis of the analysis, along with solar self-supply and solar export options for customers that would like rooftop PV. The average Hawaiian Resident's load and solar production profiles are constructed – and along with the financial incentives of various schedules and DR programs – the optimum solution was determined.

For Time-of-Use (TOU) Schedules, customers derived maximum economic value from utilizing storage to arbitrage consumption across different time periods. By shifting consumption, customers were able to achieve payback periods of under two years, and significant bill savings. While adding solar panels to their roofs also created a viable economic case – the TOU rate structure often conflicted with solar production, leading to a less-than-optimal result.

For Flat Rate Schedules on the other hand, customers derived maximum economic value from employing solar PV systems (without storage) and exporting excess solar to the grid. Without the battery, the upfront costs of the system were much lower than other options and coupled with a decent export credit rate – the customers were able to attain payback periods under four years.

The report concludes that while these two options would be beneficial to customers, there is significant room for further exploration. This could include redesigning or refining the TOU Schedule and modeling various system size combinations.

Ultimately, designing a 21st-century renewable system would require going beyond optimizing for a single customer but also modeling the grid impacts of choices different customers could make. Hence, this report serves as a stepping stone to a larger exploration of the grid of the future.

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1. Introduction

In 2015, Hawaii became the first US state to declare a 100% Renewable Energy target, set for 2045. (Mellino)

The reasoning behind this, beyond being just environmental, was economic. Figure 2 shows that Hawaii has had historically higher electricity prices than the rest of the U.S and Figure 1 shows that that is because a major portion of electricity production is from imported oil, as of 2014.

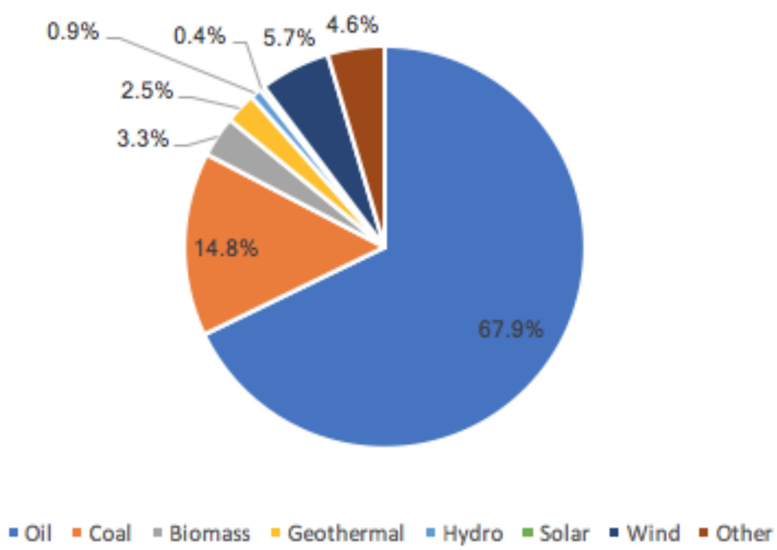

Figure 1: Hawaii's Electricity Mix, 2014 (Hawaii State Energy Office)

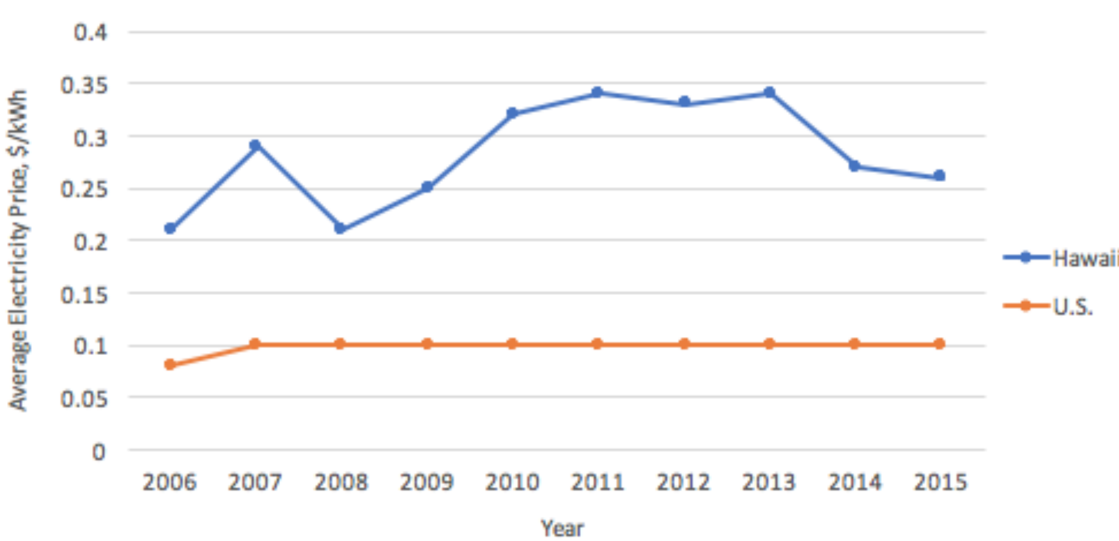

Figure 2: Historical Hawaii and US Electricity Prices (Hawaii State Energy Office)

The challenge for Hawaii goes beyond expensive electricity. This can be seen in Figure 3, which depicts the correlation between Hawaii gas & electricity prices to Crude Oil prices. As can be seen, there is a strong correlation and this creates substantial exposure to oil price risks, along with geopolitical considerations. Hence, accelerating renewables growth is not only in Hawaii's environmental interests, but its economic and geopolitical ones as well.

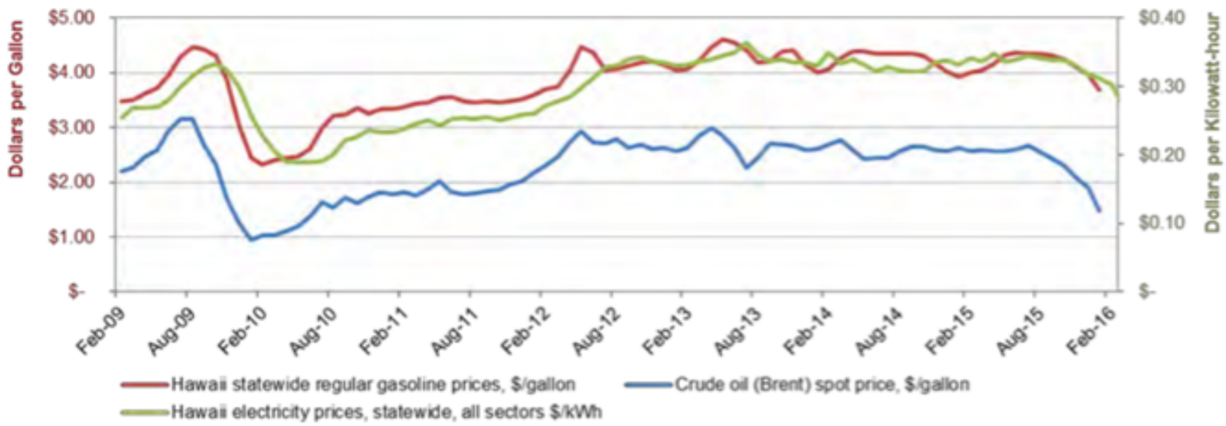

Figure 3: Correlation between Hawaii prices and Crude Oil prices (Hawaii State Energy Office)

Figure 4 below shows that Hawaii has been making significant progress in the renewables space, with progressively increasing RPS levels

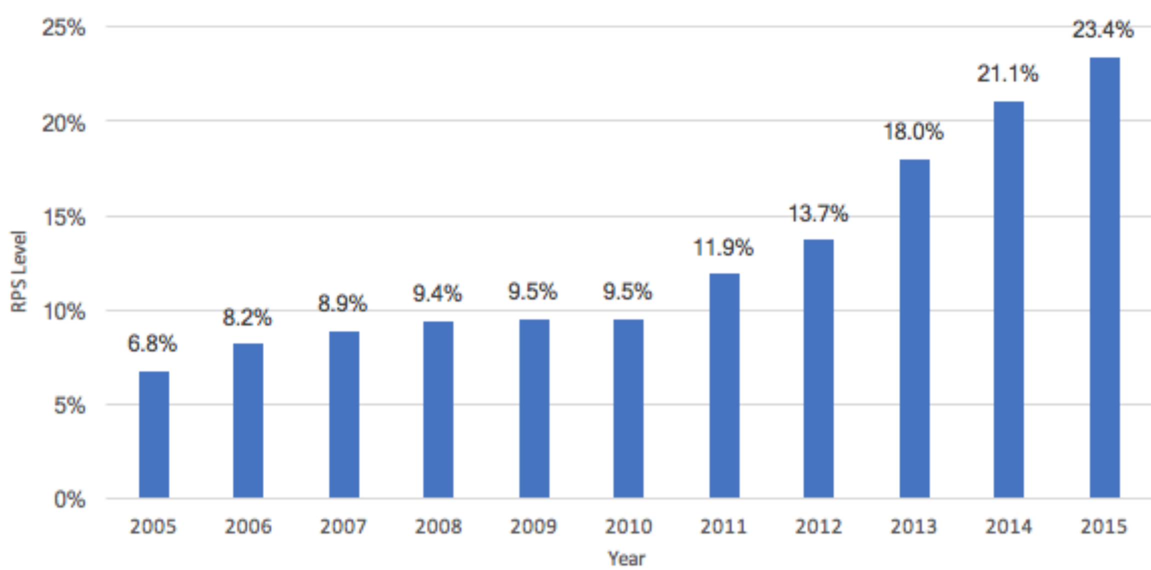

Figure 4: Hawaii's RPS levels over the years (Hawaii State Energy Office)

Despite significant progress being made in the last few years, to reach a 100% Renewable Energy target requires a dynamic, interactive electricity system that can manage the intrinsic intermittency of renewables while ensuring a high quality of electricity supply to customers.

Demand flexibility is one option to help achieve this goal and has been shown to theoretically boost economic value for customers while requiring minimal grid infrastructure upgrades. (Dyson and Mandel)

The following section will seek to define what demand flexibility is, the state of Hawaii's interest in it and what value it can bring to customers.

2. Defining demand flexibility

Demand flexibility uses communication and control technology to shift electricity use across hours of the day while delivering end-use services (e.g., air conditioning, domestic hot water, electric vehicle charging) at the same or better quality but lower cost. (Dyson and Mandel)

Demand flexibility has *two main components* (Dyson and Mandel)*:*

1. *Real-time reshaping of customer load profiles* - this involves shifting the use of non-critical loads in a manner that does not require a change in customer behavior
2. *Utilizing granular retail rates to bring value* - time-of-use or real-time rates are examples of more granular rate structures which demand flexible services can exploit to bring value and lower costs for customers

Given the dynamic nature of demand flexible services, it is easy to understand the state of Hawaii's interest in the set of technologies as they allow for more real-time, second-by-second balancing that could ensure grid supply quality for customers.

The Hawaii's Public Utilities Commission (PUC) describes a competitive demand flexibility market that brings values to customers in two ways:

- "dynamically-priced services that allow for direct or indirect customer participation, and
- afford[s] market participants, such as intermediaries or aggregators, the opportunity to bid for the delivery of grid services based on system needs." (Docket 2015-0412)
-

The PUC also sees the proliferation of demand flexibility services as a way to transform its traditional electricity companies to grid operators, balancing demand and supply on a real-time basis. (Docket 2015-0412)

If a competitive demand-flexibility market is to make the Hawaiian electric grid more real-time, more dynamic and yet as reliable, there are a host of grid services it needs to fulfill while driving customer value for them.

The four most important services are described in the section below.

3. The grid services provided by demand flexibility

Table 1 (Docket 2015-0412)**:** Different types of demand services, their descriptions and duration of operation

Type of demand service	**General Description**
Fast Frequency Response (FFR)	Reducing the Rate of Change of Frequency (RoCoF) caused by a loss of generation
Regulating Reserve (RR)	Comes on after FFR, maintaining system frequency in response to demand/supply imbalances
Replacement Reserve/ Non-Spin Auto Response (NSAR)	Off-line, quick start resources to support the grid. Come on after RR
Capacity	Longer-term, slow-start resources brought online/offline for grid support

While these various services serve important functions individually, this report will also aim to explore value stacking of the services and if it can bring greater customer value. Value stacking involves bundling various compatible services together, taking into account the incentives and constraints associated with each service. This is further explored in Table 2 below, where services or rate schedules that are not compatible with each other are highlighted as “Not eligible to value stack” under Key Constraints.

Table 2: (Docket 2015-0412) Incentives and constraints for different demand flexibility services

Demand Flexibility Service	Incentive Payments	Key Constraints
Fast Frequency Response (FFR)	*Residential, Small & Medium Business* - $8/kW.month *Commercial* - $4/kW.month; $600/kW one-time	Min. 50 kW for Commercial *Not eligible to value stack:* Regulating Reserve
Regulating Reserve (RR)	N/A	N/A
Replacement Reserve/ Non-Spin Auto Response (NSAR)	*Residential, Small & Medium Business* - $6/kW.month *Commercial* - $3/kW.month; $600/kW one-time	Min. 50 kW for Commercial *Not eligible to value stack:* Regulating Reserve, certain Capacity schedule
Capacity	*Residential, Small & Medium Business* - N/A *Commercial* - $3/kW.month; $600/kW one-time	Min. 50 kW capability, At Least 200 kW *Not eligible to value stack:* Regulating Reserve, NSAR

4. Rate Schedules Considered for Modeling

Schedule R

Hawaii Electric Company (HECO)'s Schedule R is one of two primary rate schedules considered for this modeling. It is a flat rate through the entire day and the final bill is dependent on which tier energy consumption falls in, as can be seen in Table 3. Other fees and charges are also involved and can be found here. (Hawaiian Electric)

Table 3: Schedule R Rate Structure

Energy Consumption Tier	Value (cents/kWhr)
First 350 kWhr in a month	8.1034
Next 850 kWhr in the month	9.2569
All kWhr above 1200 kWhr that month	11.1343

Schedule TOU-RI

HECO's Schedule TOU-RI is the other primary rate schedule used in this modeling and its tiered rate structure and billing periods are seen in Table 4. Other fees and charges are also included and can be found here. (Hawaiian Electric)

Table 4: Schedule TOU-RI Rate Structure

Billing Period	Period Length	Period Charge (cents/kWh)
On-Peak Period	5pm - 10 pm, Daily	35.1826
Mid-Day Period	9am - 5pm, Daily	12.807
Off-Peak Period	10pm - 9am, Daily	21.5810

Consumer Self Supply (CSS) Program

This program is designed for residential customers with rooftop solar that are looking to offset their load as much as possible and importing the remainder from the grid. It, thus, does not allow for the export of excess solar to the grid. It can be used as an adder to basic schedules, such as Schedule R and Schedule TOU-RI - and will adopt the same rate structure as them. (Hawaiian Electric).

Consumer Grid Supply (CGS) Program

This program is designed for residential customers with rooftop solar looking to offset their load and export the excess solar to the grid. Customers receive an export credit of 15.07 cents/kWh. However, to ensure that customers do not oversize their systems and overload the grid, the program only compensates customers on whichever volume of electricity is lower - the amount exported to the grid or the amount imported from the grid. (Hawaiian Electric)

5. The technologies considered for enabling demand response

Value stacking does not only include rate schedules and demand services but also technologies to enable them.

Technologies that would enable demand flexibility have to have the following characteristics:

1. *Commercially feasible* - any technology considered must be beyond the R&D phase and currently available for purchase. Moreover, it must be relatively commercially viable and moderately priced.
2. *Available to average customer* - beyond commercial feasibility, the technology should also be relatively easy to attain for the average customer and available in various geographies.
3. *Technically capable* - the technology should be capable of performing demand flexibility services - whether that's by curtailment or load shifting (through storage).

Based on the three criteria described above: Batteries, Electric Vehicles, Hot Water Heaters and Air Conditioners were chosen. For the scope of this report though, storage - specifically batteries, will be the main focus.

To choose a specific battery, comparisons of three leading battery manufacturers were done - Tesla, Sunverge and Sonnenbatterrie. These can be seen in Table 5.

Table 5: Various battery specifications and characteristics

Battery type	Capacity (kWh)	Discharge Rate (kW)	Total Cost per unit ($)	Cost per kWh ($/kWh)	Cost per kW ($/kW)
Tesla Powerwall (Tesla)	13.2	5	7600	575.76	1520.00
Sunverge SIS – 6848 (Sunverge Energy)	16	8	24300	1518.75	3037.50
Sonnenbatterrie Eco 16 (sonnenBatterie)	11.6	6	19146	1650.52	3191.00

While it is important to ensure that each battery has enough capacity to match well with the household's consumption, the economics of the battery are paramount. As can be seen clearly from Table 5, the Tesla Powerwall has superior economics on the $-per-kWh and $-per-kW front - along with significantly lower upfront cost. Hence, the Tesla Powerwall is selected for further modeling and will be used from here on out.

6. Parameters that were chosen and value stacking

From the previous sections, it is clear that the two primary rate schedules that will be explored include Schedule R and Schedule TOU-RI, along with the CSS and CGS programs for solar cases. The battery that will be modeled is the 5 kW, 13.2 kWh Tesla Powerwall and the solar system size will be 5 kW (the “right-size” of a typical American household).

Even though there are four possible DR services to model - the FFR and NSAR services will be exclusively modeled, due to time constraints. These will also be bundled together whenever the system participates in Demand Response - as they do not conflict with each other and indeed, add value.

All these parameters are now value stacked in different combinations and through the course of the modeling, the combination producing the most economic value for the customer will be highlighted. This value stacking can be seen in Table 6 below.

Table 6 - Value stacking of rate schedules, DR services and solar systems

Case Number	Use Case	Solar Tariff	Rates	DR Services
No Solar				
1	Base Case	-	R	-
2	DR base case	-	R	FFR + NSAR
3	TOU base case	-	TOU-RI	-
3.5	TOU Arb	-	TOU-RI	-
4	TOU+ Arb +DR	-	TOU-RI	FFR + NSAR
Solar with Customer Self Supply (CSS)				
5	CSS	CSS	R	-
6	CSS+DR	CSS	R	FFR + NSAR
7	CSS+TOU	CSS	TOU-RI	-
8	CSS+DR+TOU	CSS	TOU-RI	FFR + NSAR
Solar with Customer Grid Supply (CGS)				
9	CGS	CGS	R	-
10	CGS+DR	CGS	R	FFR + NSAR
11	CGS+DR+TOU	CGS	TOU-RI	FFR + NSAR

7. Modeling Assumptions

- ***General assumptions for all cases -***
  - *Solar System Size* - as there were many variables involved in these modeling scenarios, the solar system size for an average home was fixed at 5 kW across all scenarios. This is the system size for an average American home, according to SEIA. (Solar Energy Industries Association (SEIA))
  - *Residential Battery System* - the Tesla Powerwall 2, with 13.2 kWh of storage, 5 kW discharge rate and 89% roundtrip efficiency (Tesla), was chosen for all relevant modeling scenarios. The reasoning for this was clarified in a previous section.
  - *Fast Frequency Response (FFR) Constraints* - According to HECO's requirements for the program, the nominated resource needs to be available 24x7 for FFR services, and must be available for at least 30 minutes at one time. [From Hawaii DR Overview 170508.pptx]
  - *Non-Spin Auto Response (NSAR) Constraints* **-** According to HECO's requirements for the program, the nominated resource needs to be available 24x7 for NSAR services, and must be available for at least 60 minutes at one time. [From Hawaii DR Overview 170508.pptx]
  - *Demand Response (DR) Event Frequency* - There can be no more than two DR events within 24 hours.
  - *Residential Load Data* - Residential Load data for the model was obtained from the OpenEI platform, for a typical Hawaiian household. (Wilson)
  - *Solar Production Data* - Solar production profile for the panel system was determined from the OpenEI platform - for solar irradiation falling in that region.
- ***Technical constraints/assumptions for all cases -***
  - *Solar panel efficiency* - for all relevant modeling scenarios, the efficiency of the solar panels is assumed to average 16.2%, based on Canadian Solar estimates. (Canadian Solar Inc.)
  - *Steady power rate of battery* - the Tesla Powerwall's 5 kW discharge rate is factored into all relevant modeling scenarios, and is a key constraint for the maximum rate at which the battery can charge or discharge power
  - *Roundtrip efficiency of battery* - the Tesla Powerwall's 89% round-trip efficiency is factored into all relevant modeling scenarios. Since it is a round-trip efficiency, it is applied every time the battery discharges power while operating.
- ***Constraints from DR Program Participation***
  - *Minimum battery level* - As stated by the constraints of the FFR and NSAR programs, the nominated resource needs to be available 24x7 to be called upon for DR services. As this study is coupling FFR & NSAR services, the maximum nominated resource needed is 60-min of steady power draw from the battery. Because the battery

in this case is a 5kW PowerWall, a minimum of 5 kWh needs to be available at all times when the customer is participating in DR programs.

8. Modeled scenarios – Schedule R

Case 1 - Base Case, Schedule R

What this includes

Case 1 is the base or reference case that other scenarios will be compared to. Hence, it involves an average household consuming energy without any change in behavior, without solar panels on their rooftops or any form of storage. This household will be billed according to Schedule R, as seen in Figure 5 below.

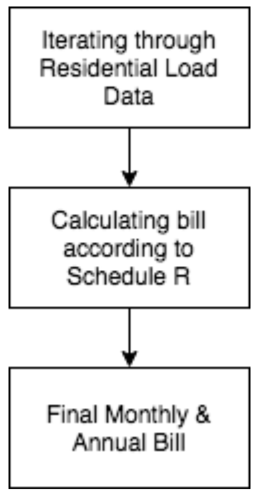

Figure 5: The modeling process for Case 1

Case 2 - DR Base Case, Schedule R

What this includes

Case 2 is the base DR case, and builds on Case 1 above. It involves an average household consuming energy without any change in behavior and without solar panels on its rooftop. However, the household does participate in DR events (FFR and NSAR) and thus, has a Tesla Powerwall attached to the house.

As mentioned in the earlier section on constraints, participating in DR services requires a minimum nominated resource of 5 kWh to be available at all times. This means that during normal operations, the state of charge of the battery must, at all times, be maintained above this level. Hence, the nominated resource of 5 kWh is not to be used for regular operation. The importance of this can be seen in Figure 6 below.

If a DR event occurs and the battery's State of Charge falls below the required minimum level, the first priority is always given to charging said battery above the required levels. If the battery levels are maintained above 5 kWh, the rest of the process - consumption and billing - proceed similarly as they did in Case 1.

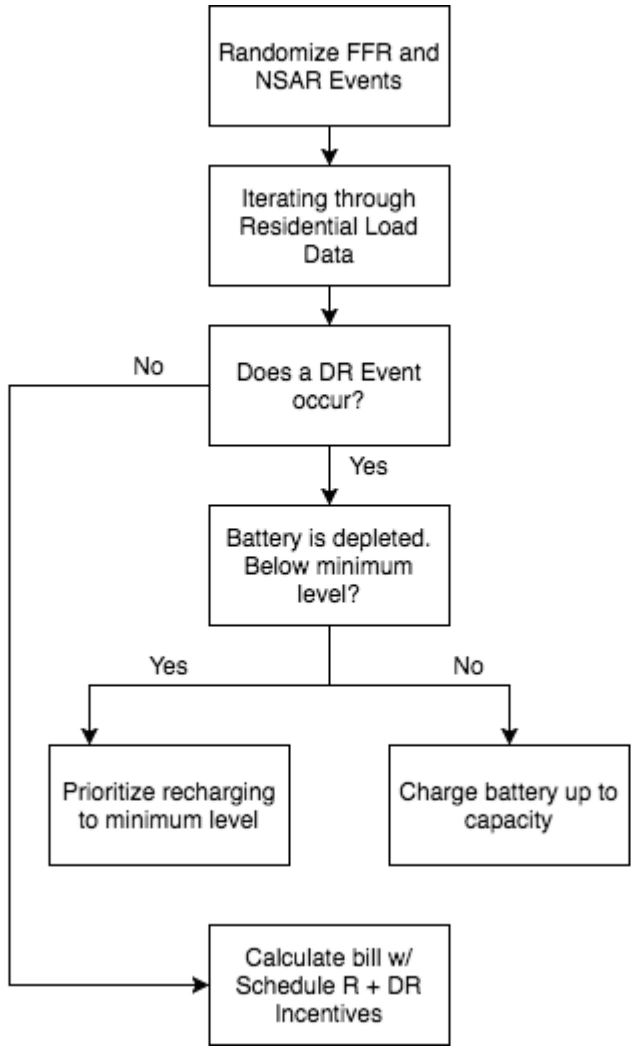

Figure 6: The modeling process for Case 2

Case 5 - CSS, Schedule R

What this includes

Case 5 includes solar panels on the customer's rooftop and has a battery to ensure the optimum use of the self-supply option. As the name implies, the self-supply options involves utilizing the solar production from the panels to first satisfy existing load - after which the attached batteries are charged. As the rate schedule is a flat rate, there is no preferential time to charge/discharge and hence, happens whenever is necessary. This can be seen in Figure 7 below:

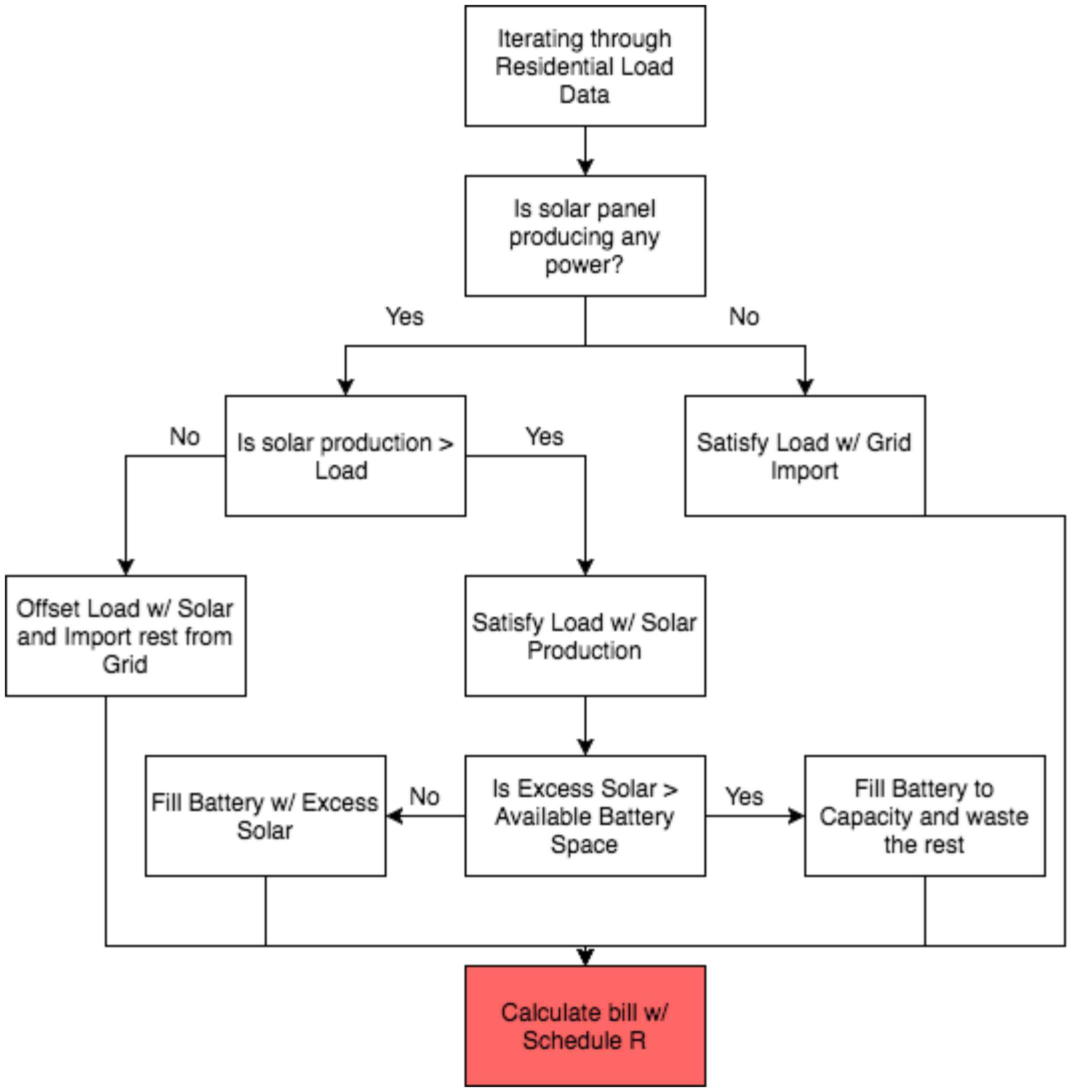

Figure 7: The modeling process for Case 5

Case 6 - CSS, Schedule R, DR

Case 6 is very similar to Case 5, with the exception that the household participates in Demand Response (DR). As can be seen from Figure 8, when there is no demand response event or when the demand response event does not cause battery levels to fall below the minimum level - the algorithm proceeds exactly how it does for Case 5.

If the DR event does occur and the battery's State of Charge falls below the minimum required level, as in Case 2 - charging the battery to above that level is prioritized first, after which the CSS-without-DR algorithm once again takes over.

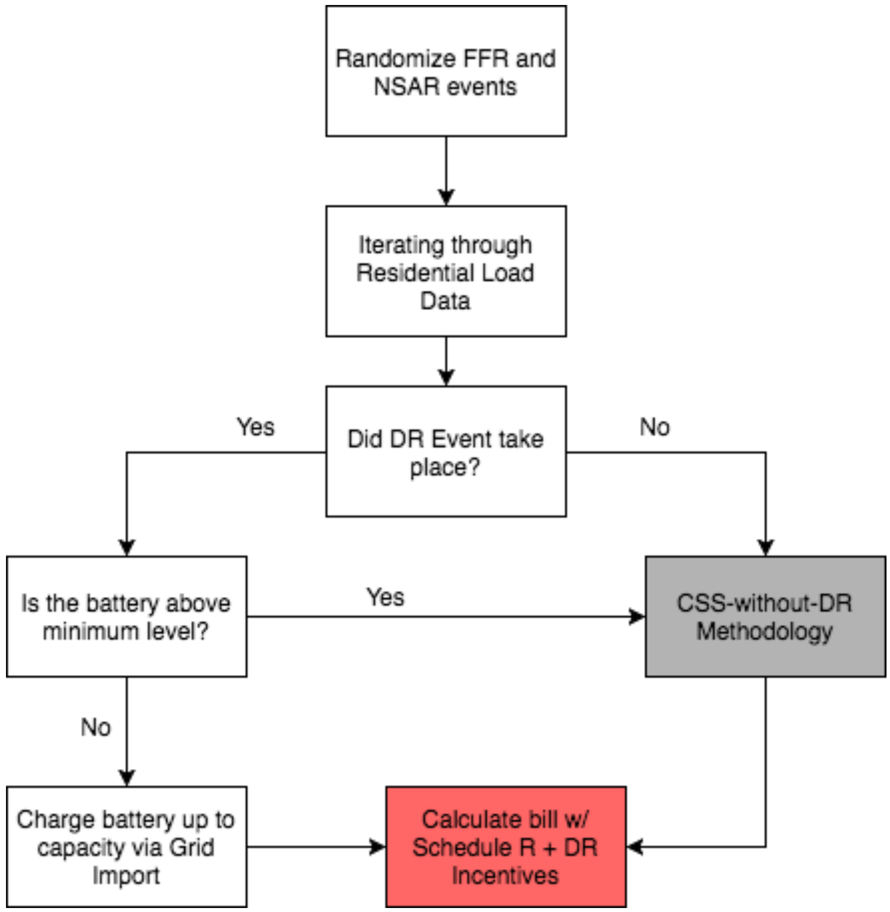

Figure 8: The modeling process for Case 6

Case 9 - CGS Only

What it includes

Case 9 is similar to Case 5 in that it involves a 5 kW solar system and is based on Schedule R. It does not include the 13.2 kWh battery however, as the system is allowed to export energy to the grid during periods of excess.

The algorithm for this case is shown below in Figure 9, wherein if there is excess solar production at any instance of the system's lifetime - the system exports this energy and is credited for it at the end of the month. If there is not enough solar to satisfy the load, the deficit is imported from the grid.

The export credit is taken into account when calculating the annual bill for the system.

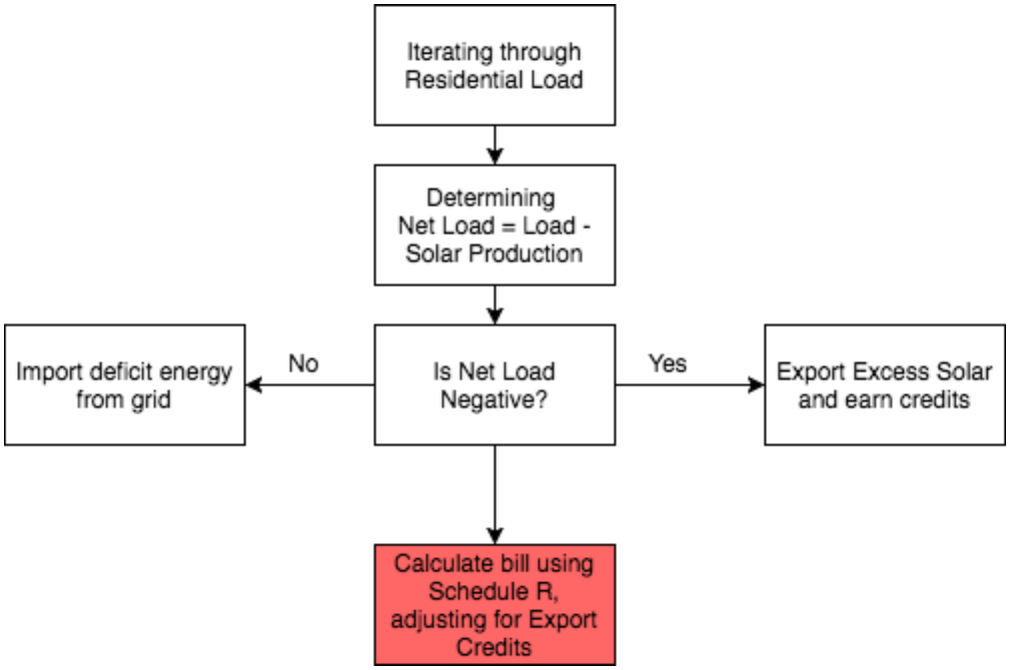

Figure 9: The modeling process for Case 9

Case 10 - CGS + DR

What it includes

Case 10 is identical to Case 9, except that it includes a system that is sensitive to demand response requests. This system still includes a 5 kW system, a 13.2 kWh Tesla Powerwall and the ability to export solar power at the rate described in Table 4.

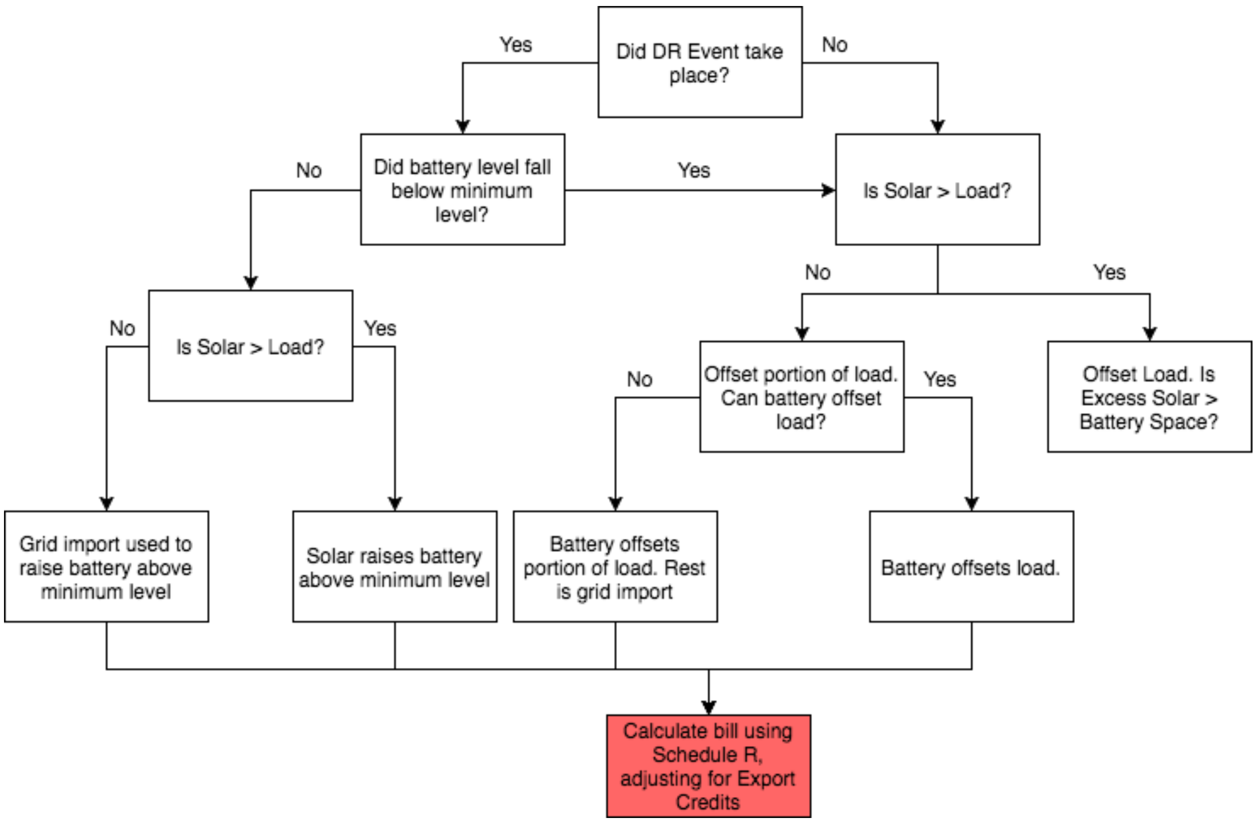

Figure 10: The modeling process for Case 10

As Figure 10 shows, in the case a DR event occurs and the battery's state of charge falls below the minimum level - solar production is used to bring that above the minimum level (if there is enough solar). If there is not enough solar, energy is imported from the grid to do so. If a DR event does not occur, self-supply is still prioritized and once the load has been offset and the battery is fully charged - the system then exports energy and receives credits for it.

At the end of each billing cycle, the bill is calculated using Schedule R and with the export credit adjustment, the final bill is charged.

9. Modeled Scenarios – Schedule TOU-RI

Case 3 - TOU Base Case

What it includes

This case is the base Time-of-Use case, wherein there are no solar panels or batteries or DR events. There is no change or shift in consumption behavior either, with the consumer simply consuming electricity in the same manner he did for Case 1.

The main difference from Case 1 is that a differential rate structure is applied here to calculate the final bill and this structure can be seen in Table 4. Depending on what time of the day it is, customers can be charged between 12 to 35 cents/kWh for their consumption. This can be seen in Figure 11.

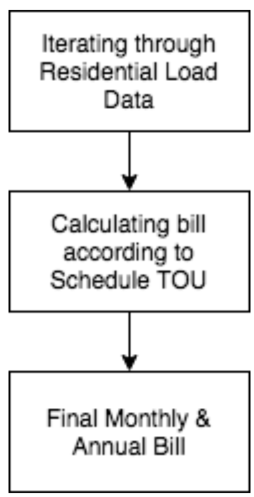

Figure 11: The modeling process for Case 3

Case 3.5 - TOU Arbitrage, No DR

What it includes

This case does not include solar panels or participating in Demand Response. It does, however, include the battery as it attempts to arbitrage between the three different rate periods to find the most economically favorable outcome for the customer.

As Table 4 shows, the Midday period is the most favorable for consumption, with the lowest rates, in comparison to the two other periods. Hence, as seen in Figure 12, the algorithm controlling the system has different responses for Midday and Non-Midday periods.

If the customer is in the Midday period, the customer's load is satisfied with importing electricity from the grid and if the battery is not at capacity - it is charged during this period as well. As electricity is the least expensive during this period, the priority is to maximize consumption.

By contrast, if the customer is either in the On-Peak or Off-Peak Period - and if the battery is not empty, it is used to offset some or all of the customer's load. Grid import for satisfying the load is the last resort as the electricity during the two periods is relatively expensive.

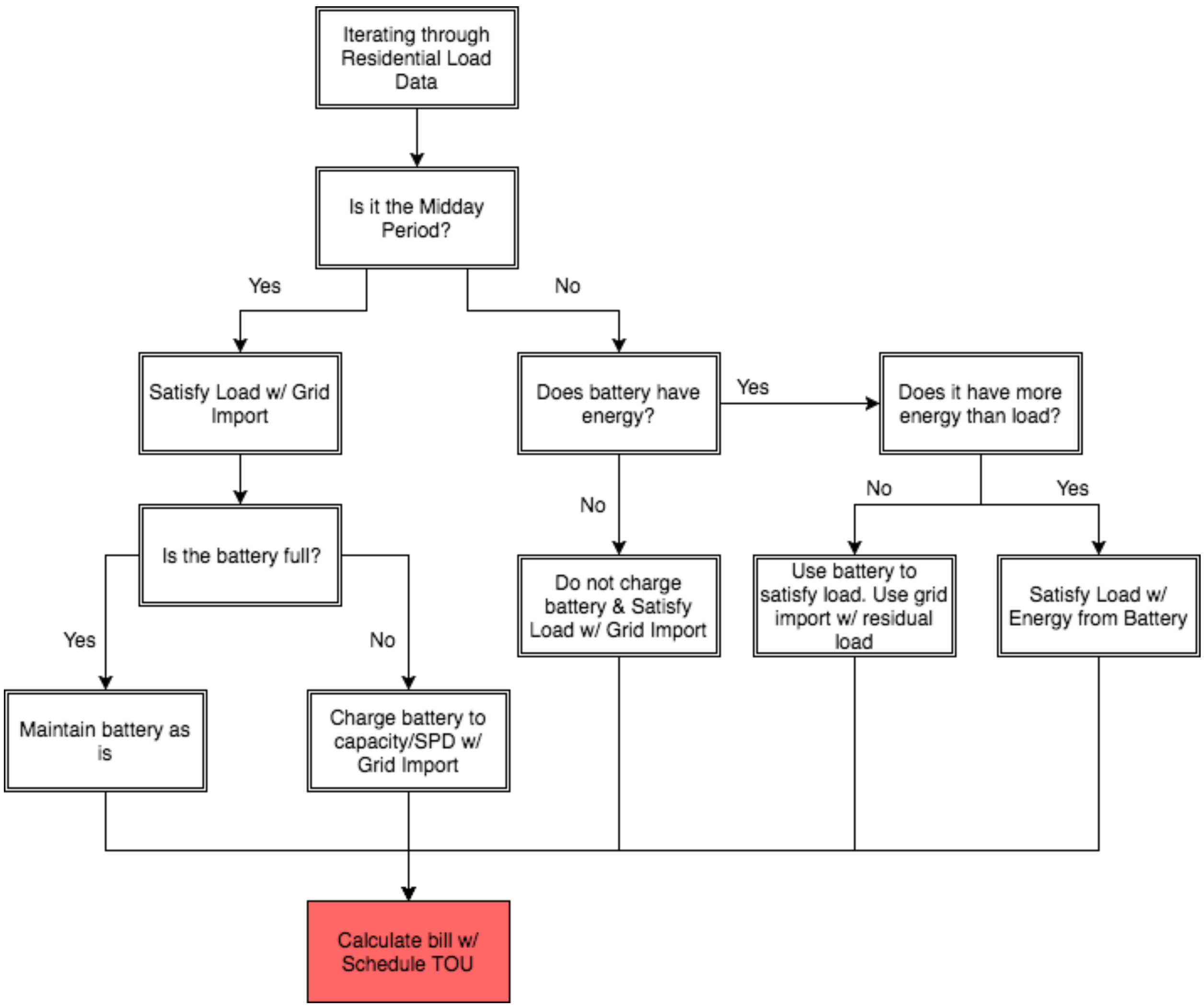

Figure 12: The modeling process for Case 3.5

Case 4 - TOU Arbitrage + DR

What it includes

This case is very similar to Case 3.5, except that it also involves a customer participating in the Demand Response programs. Thus, the same battery is used to arbitrage between the three different TOU rate structures and to respond to DR events when necessary.

As has been explained before and can be seen in Figure 13, in the event that a DR event occurs and the battery's State of Charge falls below the minimum level - charging the battery above that level is prioritized (before any arbitrage is performed).

Besides this case, the system operated identically to Case 3.5 and all final bills are calculated using TOU rates and the relevant DR Incentives.

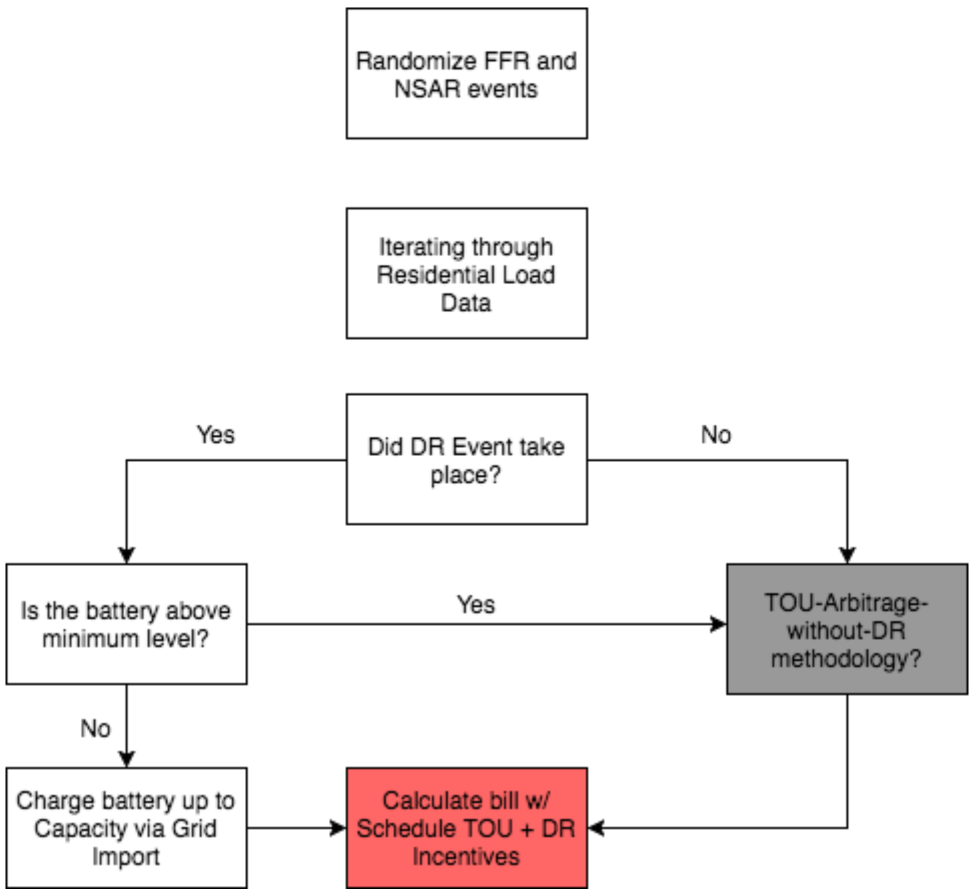

Figure 13: The modeling process for Case 4

Case 7 - CSS + TOU, No DR

What it includes

This case includes a 13.2 kWh battery and a 5 kW solar system. The schedule involved is the CSS (Consumer Self Supply) one, where no export of electricity to the grid is allowed. Hence, all locally produced power must either be consumed locally or curtailed. This schedule is then combined with the TOU Schedule, with its retail rates shown in Table 4. There is no demand response in this situation.

Figure 14 shows the logic of the algorithm for this case. If the current hour is in the midday period (as specified by Table 5), importing energy from the grid is prioritized until the load is satisfied and the battery is at full capacity. The reason behind this is that, as seen in Table 4, this period's rates are the lowest and hence, it is the most advantageous period to buy energy in.

In the off-peak and on-peak periods, Figure 14 shows that self-supplying the load is prioritized - wherein either the solar panels or energy from the battery, is used to offset load. As a last resort, energy is imported from the grid.

This logic is designed to minimize annual bills for the customer and thus, maximize the economic payback.

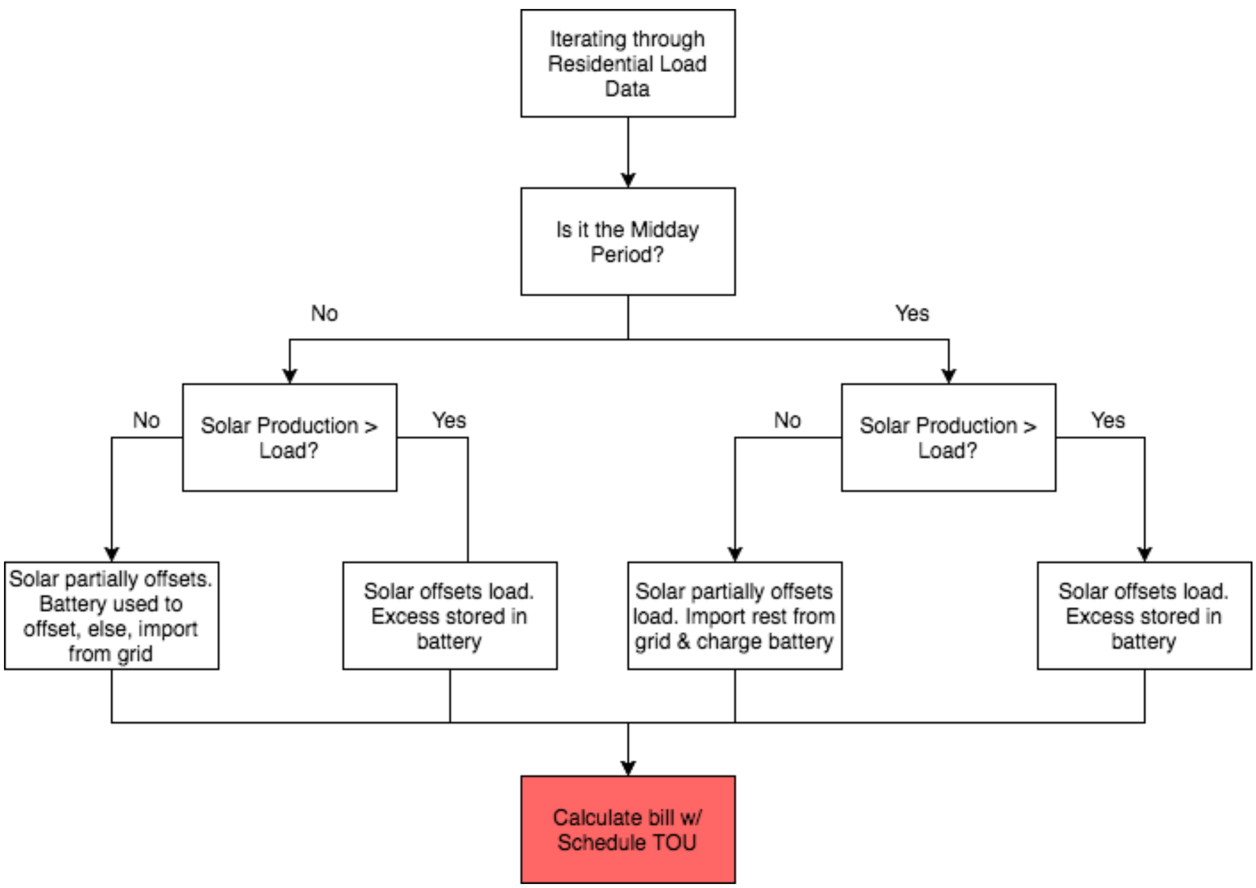

Figure 14: The modeling process for Case 7

Case 8 - CSS + DR + TOU

What it includes

Case 8 is identical to Case 7 except it includes the system responding to DR events - and retaining the capacity to do so throughout its operation. This can be seen in Figure 15.

If no DR event takes place, the logic of this algorithm is identical to that of Case 7. If a DR event does take place but the minimum level of the battery is maintained, the logic of the algorithm is again identical to that of Case 7.

However, if a DR event takes place and the battery's State of Charge falls below the minimum level needed for DR events, the algorithm attempts to meet some or all of the energy needed to cross that minimum threshold, from solar panel production. If there is still a deficit, it is covered with imported energy from the grid.

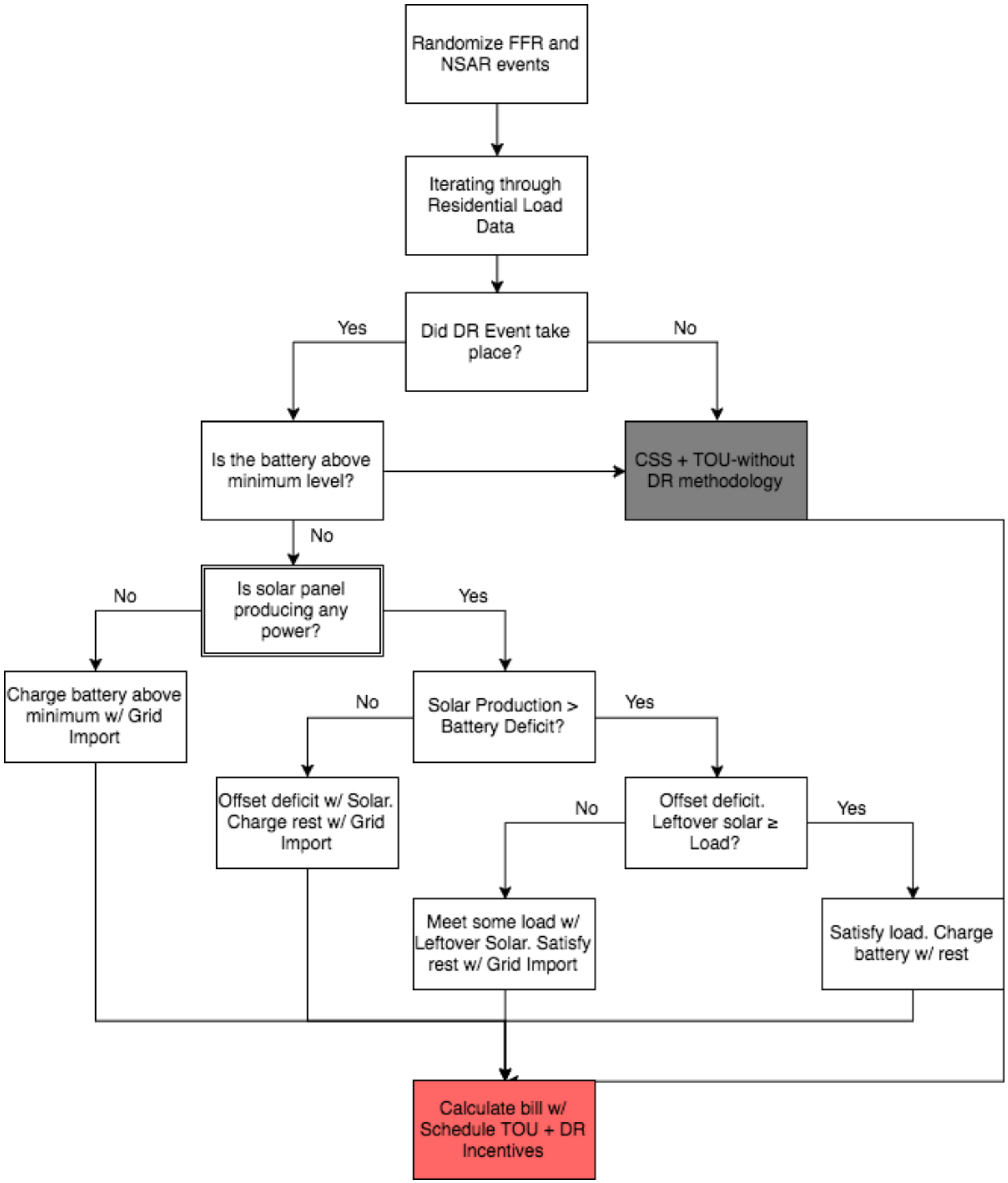

Figure 15: The modeling process for Case 8

Case 11 - CGS + DR + TOU

What it includes

This case is similar to Case 10 in many ways, except that it allows for solar export when necessary. Thus, it consists of a 5 kW solar system, along with a 13.2 kWh Tesla Powerwall. Figure 16 shows the logic behind the algorithm for this case. If there is excess solar production, the load is always offset first. Then, if the system is in the Midday period (with lower electricity rates), the battery is charged to capacity as well via grid import. If the system is in other periods, no battery charging takes place. In both cases, only if the battery is full and the load is satisfied - is the solar power exported.

In the case a DR event occurs and the battery falls below the minimum level required, solar production is prioritized to be used to charge that battery above that level. After that, it is used to ensure as much of the load is satisfied as possible.

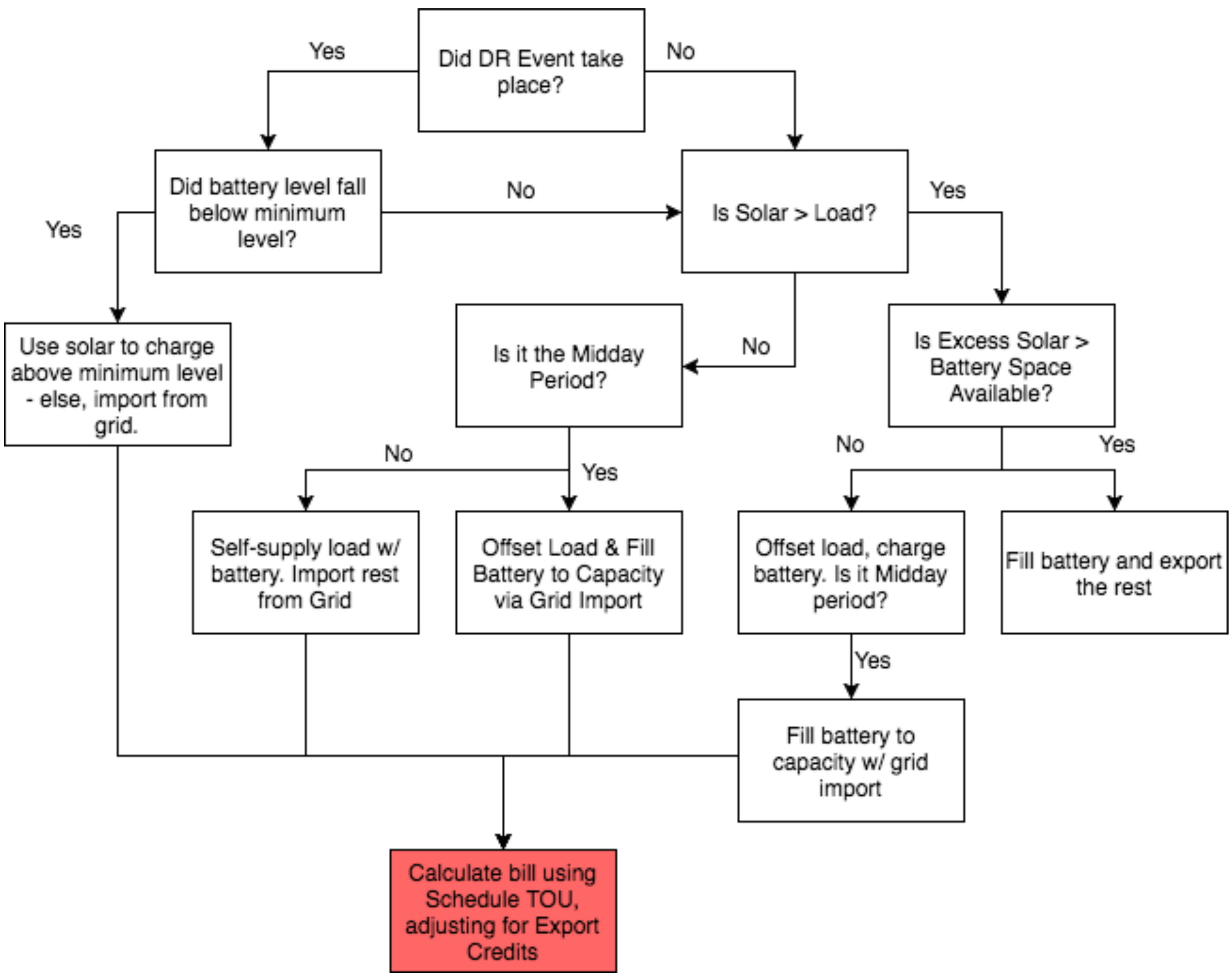

Figure 16: Modeling process for Case 11

10. Modeling Results

Table 7: Results from modeling all cases - annual bills and simple payback

Cases	Case Descriptions	Annual Electricity Bill ($/yr)	Simple Payback (yrs)
No Solar			
1	Base Case	6808.2	-
2	DR Base Case	5968.2	9.05 years
3	TOU Base Case	6498.9	-
3.5	TOU Arbitrage	3418.5	2.24 years
4	TOU Arbitrage +DR	5036.3	4.3 years
Solar with Customer Self Supply (CSS)			
5	CSS	3899.7	6.21 years
6	CSS+DR	3164.4	4.95 years
7	CSS+TOU		
8	CSS+DR+TOU	3405.3	5.3 years
Solar with Customer Grid Supply (CGS)			
9	CGS	4184.5	3.98 years
10	CGS + DR	3098.4	4.86 years
11	CGS+DR+TOU	3326.1	5.18 years

11. Modeling Insights

The results from Table 7 show the annual bills corresponding to each case. Also, every case's simple payback is calculated with respect to Case 1, the Base Case - which involves consuming electricity with Schedule R.

One trend is clear from this - adding the Demand Response option to a case generally reduces annual bills and improves the simple payback. Participating in demand response guarantees a monthly incentive regardless of how many events occur and as this usually does not involve adding more equipment - payback improves. This can be seen between Case 1 and Case 2, Case 3 and Case 4, Case 5 and 6 etc.

The one exception to this trend is between Case 9 and Case 10. While the annual bill did decrease from Case 9 to 10, the simple payback period increased. The reason behind this is that in the CGS-only case, the system does not have a battery system and is simply exporting any excess solar production. However, to enable a DR response, a battery needs to be added - which is why simple payback actually increases in Case 10.

Within the cases involving Schedule R - it can be seen that adding a solar panel system significantly improves the economics for the customer. For example, Case 9 (CGS Only) ends up saving the customer $2,623.7 per year and delivers a simple payback of 3.98 years in comparison to Case 1 (Base Case). Similarly, Case 6 (CSS + DR) saves the customer $3,643.8 per year, paying back in 4.95 years. When comparing Cases 6 and 9 to Case 2 (DR Base Case), this trend is clear. While other systems save the customer more money, among the cases with Schedule R, Case 9 promises a relatively low upfront cost (only a solar system) with a decent payback period.

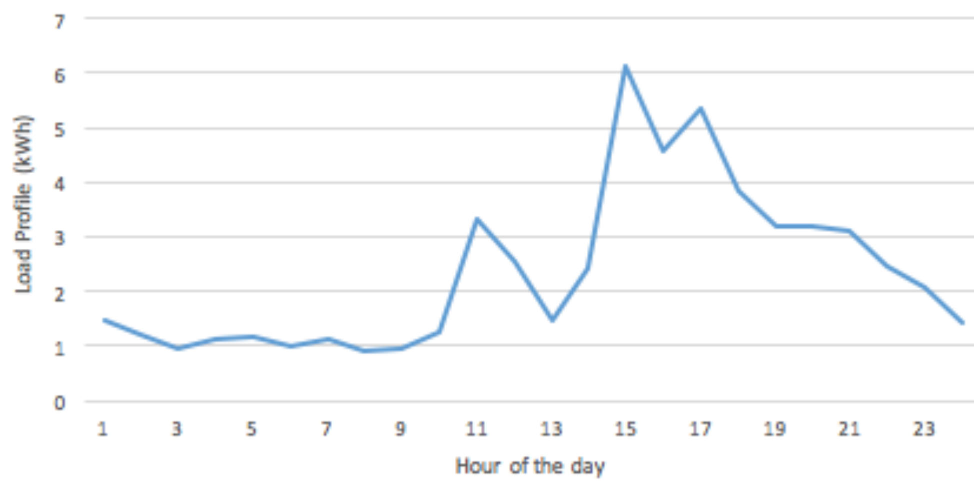

Figure 17: Representative Load Profile of Residential Customer

As Figure 17 shows, the load profile of a residential customer varies through the day. As can be seen, the curve is far from flat and has significant peaks during certain hours - which make it difficult and often, expensive to meet that load. This is the primary reason for a Time of Use or TOU Schedule. A TOU schedule is ideally supposed to financially encourage consumption during off-peak periods and subsequently, discourage consumption during high-demand periods. It thus, seeks to flatten out the load curve.

Within the No Solar Cases, it can be clearly seen that the TOU schedule far outperforms the R schedule economically. As customers are equipped with storage and given financial incentive to consume differently - they take advantage of a tiered TOU rate structure. This is particularly true for Case 3.5, which demonstrates the best economic performance of all cases in terms of payback period. This case includes just the 13.2 kWh Tesla Powerwall to arbitrage power during different time periods to save the customer money without modifying the customer's behavior. The main reason this case is so economically favorable is because of the relatively low upfront cost. As it did not include solar production, the only cost to bear was the battery's and within a little over two years, that investment was paid back.

With the Solar Cases, however, like Cases 8 and 11 - the system underperforms economically compared to the Schedule R counterparts - Cases 6 and 10. The reason behind this can be seen in Figure 18. The figure shows solar production for the system, along with solar waste and state of charge for the CSS+DR and CSS+DR+TOU cases.

As can be seen, as solar production increases in the morning, the battery starts charging rapidly in the TOU case and reaches full capacity much faster than the Schedule R case. The reason behind this is that, as seen in Table 4, the inexpensive, off-peak period for TOU starts at 9 am. This forces the system to import as much cheap electricity as possible.

As the battery reaches capacity faster in the TOU case, it is not able to absorb some of the solar panel's excess production. This leads to a higher amount of solar being wasted in the TOU case, as opposed to the Schedule R case. In a whole year, the TOU system wastes around 984 kWh of energy as opposed to the 438 kWh wasted by the Schedule R case. This mismatch between the TOU Schedule and Solar Production ultimately contributed to a poorer economic performance.

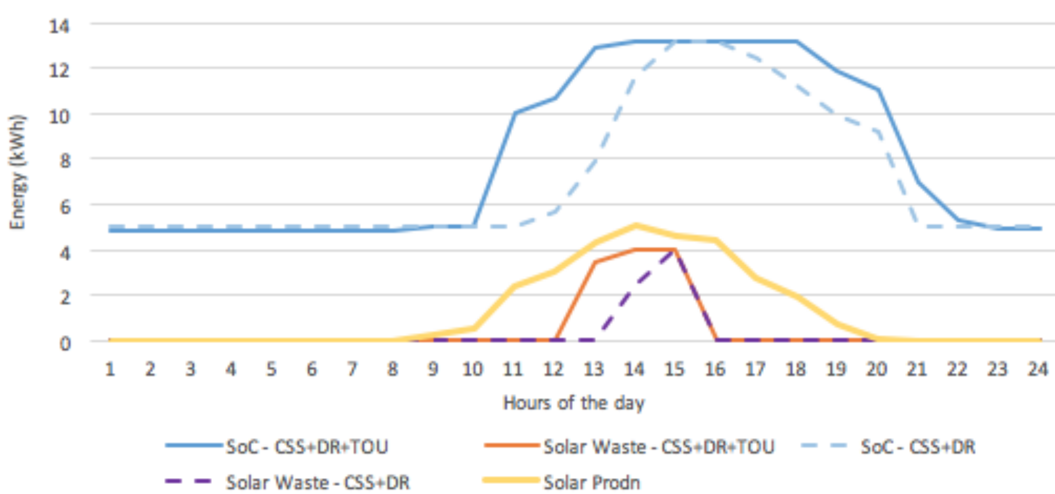

Figure 18: Solar Production, Solar Waste and State of Charge of Various Schedules

12. Conclusion

From the discussion in the previous section, it is clear that the solution to a truly dynamic, demand-response enabled system will require a combination of rate schedules and technologies - rather than a one-size-fits-all solution.

For a customer participating in a flat-rate schedule, it is advantageous to employ a rooftop solar system. Even though the upfront cost would be higher, offsetting part of the load with solar production leads to substantial bill savings and a lower payback period. Furthermore, it is even more economically beneficial for the customer to enroll in the CGS (Consumer Grid Supply) option over the CSS (Consumer Self Supply) option - to allow for bill credits to be earned from excess solar export.

For a customer participating in a time-of-use schedule, it is most advantageous to solely employ the use of a battery to adjust time of consumption and arbitrage across the various time-of-use periods to maximize economic value.

Assuming that the proposed rate schedules and grid constraints remain unchanged, there are two possible outcomes that could bring substantial value to customers. The first is enrolling in a CGS program, coupled with Schedule R, to export excess solar when the need arises. The second option is arbitraging with the TOU schedule with a battery, and to have some form of aggregated solar production offsite. This could take the form of a community-scale solar project, for example, and is important is the vision of a 100% Renewable System is to be realized. Both options could allow for systems to participate in Demand Response events when needed.

There are however, other available options for a path forward towards a dynamic renewable system and these are explored in the next section.

13. Further Exploration

The extent of Demand Response needed by the grid was not clarified in this modeling problem, because of which scenarios with and without demand response were considered. For further modeling, knowing the scale of Demand Response needed would allow for more sophisticated modeling on a grid-wide level.

While the two options specified in the previous section are viable, to truly advance to a 21st-century, dynamic, 100% renewable energy system - the time-of-use rate structure would have to be redesigned. Time-of-Use and Real-time pricing are an important part of the solution to correct the mismatch between renewable energy production and customer demand. However, as was shown in this exploration - the current time-of-use rate design conflicts with solar production to some extent - preventing optimum economic utilization. Hence, further exploration of this model would require revisiting the rate schedule

Furthermore, various system sizes and component combinations can be considered. Depending on the rate schedule employed and customer preference, the system can have an oversized solar system or multiple batteries - especially if maximum export or minimum curtailment are prioritized. These options might lead to higher customer value.

Lastly, more information is needed on the grid impacts of each scenario. While this model optimizes for customer value, it does not take technical grid constraints into account. Hence, it is possible that increased solar penetration or excessive battery arbitrage start negatively impacting the grid.

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Appendix

[See Attached File]